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Q.9.1.2-1, Rev. 5 (10-17-01)

Project No.: 10171649
Project Title: WILLISTON OIL REFINERY

Transmittal Date: 04/15/08
Transmittal Number: DT-171649-003

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Description: FEASIBILTY STUDY
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Document Count: 10

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NORTHWEST REFINING

FEASIBILITY STUDY

April 10, 2008

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Feasibility Study

Objective:

The objective of this study is to determine the feasibility of a new grass roots refinery in the area of Williston, North Dakota that is designed to refine North Dakota or Canadian crude oils. The product slate should maximize jet fuel and diesel fuel production, and minimize gasoline and fuel oil production. The design will include flexibility to modify the product slate, with demand caused by shifting markets and seasonal changes that will impact the markets for asphalt, LPG, and any other changes in demand.

To reach this objective, it is necessary to evaluate:

- Supply of crude oil
- Local market for refined product sales
- Logistics and access to other product markets
- Proposed site for the refinery
- Configuration of the refinery
- Utility requirements for the refinery
- Refinery emissions
- Capital requirements for the project
- Economics of the project

Project Background:

A group of business owners organized by Mel D. Falcon of Williston, North Dakota, including business owners from Dickinson, North Dakota, Redmond, Washington, and Morgan, Utah decided to pursue the feasibility of placing an oil refinery in the Williston, North Dakota area.

Mr. Falcon established a company called Northwest Refining, Inc. and started to research the methods of establishing a format to conduct a study. He contacted ENGlobal Engineering of Houston, Texas and received a proposal that will be the format for a prefeasibility study to evaluate the feasibility before proceeding into the permitting and design phase.

Mr. Falcon and other group members had several meetings with North Dakota State Industrial Commission officials, state legislatures, and other state department officials. With the help of Tri-County Development of Williston, a proposal was submitted to the Oil and Gas Research Program of the Industrial Commission of North Dakota for a matching grant to conduct the Study. The proposal was approved and a contract was issued by Northwest Refining, Inc. and ENGlobal Engineering to conduct the Study.

Siting:

ENGlobal Engineering conducted a site visit on October 31st to evaluate the site that Northwest Refining, Inc. has chosen for evaluation. Four sites were examined and a site that would be next to an Ethanol Refinery was chosen as the most feasible. This site has many features that enhance its feasibility.

- Test wells completed two miles from the site determined that adequate water to supply the refinery is available from beach wells along the river
- Railroad access is available
- A crude oil pipeline is within the site boundaries
- Power to site is available and adequate
- Soil analysis was conducted on site and was deemed suitable for building a refinery
- Site will support a 50,000 to 100,000 BPD refinery and has room for expansion.
- Trucking access is adequate
- Drainage from site is acceptable

Subsequent to the site evaluation, some of the key parcels of land increased in value and some land owners were not willing to sell to Northwest Refining. An alternate 2,900 acre site closer to Trenton North Dakota was evaluated as a possible alternate location. This site is available and has all the amenities of the first site. In addition, river access will be on the property for beach wells (recharged from the river) to supply water and adequate existing power lines run through the site. The site is also served with city water and sewer utilities. The site is further away from the national park than the other site and the prevailing winds are away from the national park. The highway access provides access to two major roads. A crude oil receiving terminal is located close to the site providing access to crude.

The advantage the first site has over the second site is that a crude oil line runs through the site and the ethanol plant will be located next door to the site. Also, preliminary soil analysis is available on the first site indicating the soils are adequate to support a refinery.

The negotiations with the land owners will be completed in the next 30 days and the actual site will be put under option.

Both sites are suitable for the location of the proposed refinery.

Results:

The proposed refinery portion of the project will cost $1,000,000,000 to $2,500,000,000 and will pay out in 1.5 to 2.5 years. The project can handle 100% North Dakota crude oils, and maximizes the production of jet fuel and diesel fuel.

Conclusions:

The project is economically viable, environmentally viable, and can produce the product slate required by Northwest Refining.

Recommendations:

It is recommended that the project development continues.

Path Forward:

The next steps in pursuing this project are to obtain an assay for both of the potential crude sources. The assay needs to be detailed to the extent that the crude must be broken up into its constituent parts. Each part, in turn, should be assayed to determine the qualities for the product that is made from that part. (For example, cetane would be run on the part boiling in the diesel fuel boiling range).

With this information in hand, potential technology suppliers should be contacted to determine how their technology would work with the specific feed available from Northwest Refining, and what the royalties would be. This information will enable Northwest Refining to select appropriate technologies.

With the information from the potential suppliers, it will be possible to proceed with the Front End Engineering Design (FEED).

While the FEED package is being pursued, the preparation of the environmental air permit can proceed on currently available information. The completed permit application can be submitted for review and issuance of the air permit to allow construction to commence.

Crude Supply:

Consultation with Sathe Lab of Williston provided initial information and partial crude analysis. A sample of the mixed available crudes was sent to SPL labs in Houston for detailed analysis but it was determined that this sample was not typical and testing was suspended. A sample of the light local crude was obtained and analyzed with a simulated distillation analysis. From these partial assays, mathematically simulated crude was used that approximated the available crude and provided a worst case scenario for the refinery configuration.

The proposed plant site is located in the Williston Basin, which is a prolific source of crude oil. There are two types of oil available. The first is light sweet crude, which is currently produced primarily for exportation to Canada. It is used for blending with heavy Canadian synthetic crudes (from the Tar Sands) and re-importation into the U.S. The other crude oils are heavy sour crudes that are generally stranded, so they are not currently being produced and sold. A refinery in the area would provide an outlet for this oil, and would encourage greater production of additional oil reserves.

Presently, North Dakota is producing 145,000 bbls per day of crude oil and Montana is producing approximately 90,000 bpd. The Elm Coulee field in Richland County, Montana is producing 52,000 bbls per day from the Bakken formation. This field is approximately 25 miles from the proposed refinery. North Dakota has started to expand the Bakken zone and production is expected to expand rapidly. Some production companies have started to drill horizontally into zones other than the Bakken zone in the Williston Basin.

According to some producers in the Williston Basin, existing wells have been shut in or have had to slow their production of oil because, the pipelines and refineries that the oil is shipped to, are at capacity. Some new wells in the area from the Bakken zone have tremendous potential, but have to operate at a reduced rate.

According to the forecasts, the Williston Basin should have an adequate supply of crude for the next 50 years. There are many reports of how much oil is recoverable in the Williston Basin, and as new technology and drilling techniques become available, the estimates change.

Product Marketing

According to the U.S. Energy Information Administration, North and South Dakota consumed 131,531 bbls per day of petroleum products in 2005. Montana consumed 95,819 bbl per day in 2005. South Dakota has no oil refinery. Montana has refining capacity, as of January 1st of 2007, of 182,500 bbls per day. North Dakota has a 58,000 bbl per day refinery in Mandan, North Dakota operated by Tesoro. According to Tesoro, 75% of their refined products are exported into Minnesota. Montana also exports refined products to regional markets, although no statistics of exports have been gathered at this time. Between North Dakota and South Dakota, there is a short fall of 117,031 bbls per day of petroleum products from Tesoro facilities, based on 2005 statistics.

Several product pipelines have been investigated that run through the area to markets in the East and South. CHS, Inc. has a refinery in Laurel, Montana and supplies their stations in North Dakota by way of an 8 inch pipeline to Minot and Fargo. Shortages have occurred from refinery shutdowns and upgrades. Northwest Refining, Inc. and ENGlobal have approached CHS to determine if products can be shipped to Minot and Fargo though their pipeline, if there is capacity, and if additional terminal facilities are provided in Minot & Fargo. The response at this time from CHS was cordial and non committal. Currently, the 8 inch line from Montana is shipping 100% of the capacity of the Laurel refinery, with the first terminal at Minot, and ending at Fargo where it connects to the Magellan system. The Minot terminal only supplies CHS facilities due to availability (shortage) of refined products, with the balance being sent to Fargo and into the Magellan system. This leaves open the opportunity to work with CHS in the future, when the project is closer to being in production, to share terminal facilities in Minot and assist both companies with their marketing of products and shortages. At this time, adequate market is available in Minot with non CHS consumers to support the operation of an 8 inch pipeline to Minot. Based on the existence of the CHS line to this market and the size of the market area, a larger line would not be justified now or in the near future.

Magellan has refined products pipelines from refineries in Texas, Oklahoma, Kansas and some northern tier refineries. Magellan owns and operates the nation's longest refined product pipeline system, along with eighty-one petroleum distribution terminals in twenty-two states. It has distribution terminasl in Grand Forks and Fargo supplied by one 8 inch pipeline. It also has two terminals in South Dakota. According to Bruce Heine of Magellan, at a recent hearing in Bismarck conducted by Senator Dorgan, the recent shortages of gasoline and fuel in North and South Dakota is a result of refined product shortages. North and South Dakota are considered low user areas; consequently, larger markets are filled before the North and South Dakota markets, resulting in shortages and highest prices in the Nation. ENGlobal has contacted Magellan to determine if product can be shipped to the Grand Forks Terminal from Williston. The response was that, based on refinery expansions being developed and planned in the Magellan system, they may not be able to transport products to the east from North Dakota. A possible connection to the existing CHS system at Minot would provide an opportunity to trade products at Minot, without the investment of building a pipeline past Minot.

ENGlobal also investigated a large product pipeline in Canada that runs to eastern US markets. The line is approximately 70 miles north of the proposed refinery site and would possibly have capacity for the excess product generated by a 100,000 bbl per day refinery. Based on the requirements with crossing the border, and because the only tie in point to this line appears to be much further from the proposed refinery, this option was put on hold for the 100,000 bbl/day option.

Another opportunity would be to run a pipeline south along highway 85 and, with a terminal in Belfield and Spearfish, South Dakota, extending the pipeline into the Wyoming distribution system of the Casper area distribution system. The Wyoming system seems to be able to handle the excess product not utilized by North and South Dakota; however, the proposed 100,000 bbl/day refinery will not be able to produce enough jet fuel to supply all of the jet fuel being sent to Rapid City from Casper.

Local markets can be supplied by either pipeline or truck. The entire output from a 100,000 bpd refinery would be too much to sell into local markets by truck, since the economic distance for trucking is limited to about 100 miles. Provision must be made to get the product into major markets in the Dakotas. This can be accomplished by building pipelines to Minot, Belfield, and Spearfish that will serve interstate trucking and major population centers, including air force bases. Pipelines are the most efficient method of moving liquid hydrocarbons over long distances.

A proposal and cost estimate was developed to install an 8" pipeline, from the refinery to Minot, to possibly connect with the existing CHS terminal and pipeline at Minot or market direct from Minot. A southern 12" pipeline was also proposed to Spearfish with a terminal near Belfield, which will serve the southwestern part of North Dakota Interstate 94, a major east west artery, and the town of Dickinson. The terminal at Spearfish will provide products for Rapid City and Interstate 90, which is being currently served by a 6" line from Casper, Wyoming. This line is sending jet fuel to Rapid City and is at capacity with jet fuel to Rapid City. This provides an opportunity to sell all the jet fuel that the refinery can produce, plus access to Interstate 90 diesel markets and the Rapid City population.

Diesel fuel demand is driven by agriculture and cross-country trucking. North Dakota is a major agricultural state, and the farmers use diesel powered equipment in their planting, harvesting, and processing operations. Based on this market, and the use in drilling operations and trucking, the refinery will be designed to maximize diesel and jet fuel.

There are 5 Air Force bases within trucking distance and near the proposed pipeline terminals from the proposed site; therefore, it would be logical to include jet fuel as a product. The Dakotas have several major air force bases that use large quantities of jet fuel for training and defense purposes.

Gasoline will be produced, but will not be maximized, since the market for gasoline is not as strong in this area as diesel and jet fuel. Available gasoline for ethanol blending will enhance the products of both Northwest Refining and the proposed Yellowstone Ethanol plant.

The other products from the refinery, LPG, and heavy fuel oil do not have a ready local market, and other outlets for these materials must be found. LPG could be transported to market by rail, or can be used as a fuel within the refinery, supplementing the refinery gas stream and possibly producing power for consumption and or sale. A small local market is available for a small portion of the LPG which will grow when it becomes available in this area. Since LPG would require a dedicated pipeline, the installation of a pipeline for LPG would not be practical at this time. Surplus LPG can be used as feed stock to the hydrogen plant or as refinery fuel gas which will consume all the LPG produced.

The current market for asphalt is high and prices per ton are approximately $350.00. A 100,000 bbl per day refinery could generate up to 1,500 tons of asphalt a day. Up to sixty tons per day can be utilized by the coal fired electric generator plant being planned by

Yellowstone Ethanol. According to National marketing forecasts, the US demand will reach 38 million tons by 2011 which represents a 15 billion dollar market. North Dakota, South Dakota, and Montana are estimated to require approximately 1.3 million tons of asphalt in 2011. The demand for asphalt seems to be great enough for Northwest Refining to sell its asphalt at a reasonable price.

Asphalt generated has an available market and handling facility, but the market is not limitless and, with an abundance of asphalt, may become seasonal. This could require shipping some of the asphalt by rail to the west coast. The asphalt production could also be reduced with the use of a resid hydrotreater that will further process it into fuels.

The available asphalt market and current supply, along with better crude analysis, will change the amount of asphalt produced and may reduce the market, based on current suppliers of asphalt in the area. This should be instigated during the FEED stage of the design, which could reduce the capital cost of the proposed refinery.

Heavy fuel oil can be subdivided into asphaltic fuel that can be converted into asphalt for paving. There is also a clean, heavy stream that could either be sold as low sulfur oil, or as a semi-finished lube oil base stock. The remaining heavy fuel oil, which would be low sulfur in the case of the resid hydrotreater, can be utilized as either a lube oil blend stock or as a fuel for refinery heaters. This material would probably be shipped by rail once a market is developed.

LPG and low sulfur heavy fuel oil can be used as fuel for an electric generator on site, if the market is insufficient to utilize these products or while a market is being developed for these products at a higher value than fuel.

The EPA requirement for low sulfur diesel and gasoline will require the refinery to install a sulfur removal system to handle the sweet crudes and the heavy sour crudes. Northwest Refining, Inc. has contacted J.R. Simplot Companies of Pocatello, Idaho about buying of the sulfur produced by Northwest Refining Inc. Executives of Simplot have stated that they will buy all the sulfur that is produced to manufacture their fertilizers that are distributed throughout the plains states. Sulfuric acid has a large local market in water treating that would provide a strong secondary market for this by-product.

Environmental

The proposed 100,000 bbl/day refinery will be built to modern pollution control standards utilizing state of the art pollution control methods to control refinery emissions to the air, water, and land.

A preliminary look at potential air emissions from this 100,000 bbl/day refinery would indicate that all pollutants can be controlled to less than 250 tons/year from the refinery. This control would include the use of internal floating roofs with double seals on crude and gasoline tanks (required by EPA). The heaters, and possibly a gas turbine, will all be designed to burn low sulfur fuels using low NOx burners, or ultra low NOx burners, to reduce the NOx emissions to possibly less than 100 tons/year. The refinery off gas and LPG will be treated with an amine scrubber to remove all sulfur compounds prior to using them as fuel for the refinery heaters, eliminating the possibility of SOx emissions from the heaters. Heavy fuel oil will have the sulfur removed prior to burning it as fuel in the heaters, again making the emissions almost SOx free. The only source of SOx emissions will be Wet Sulfuric Acid (WSA) unit, which will include secondary emission controls to reduce SOx and NOx emissions to the lowest level possible, which will be below the allowable emissions for a sulfur removal unit. Since the primary fuel will be refinery gas and vaporized LPG (possibly supplemented with natural gas), the particulate emissions will be low. When fuel oil is being used as fuel, the stacks will be monitored for any visible plume and if a slight plume is detected, adjustments will be made to eliminate the visible plume.

Wastewater will be recycled, where possible, for reuse. When it must be discharged, it will be first treated using state of the art oil removal with all the recovered oil recycled back into the refinery. When the oil is removed the wastewater, if required, will be biologically treated to discharge standards or better, prior to discharge.

Slop oils and oily sludge will be recycled in the refinery. Spent catalysts will be sent back to the supplier for either regeneration or metals recovery, when possible. Specialized wastewater treatment will be used, if required, for spent caustic and high selenium wastewater streams. These streams will be isolated, and the selenium removed from the most concentrated streams, prior to biological treatment to assure that selenium levels are almost non-detectable in the discharge.

The environmental permit will be for the refinery, local distribution of products, and pipeline origination activities only. A separate environmental air permit application will be prepared for the pipeline and pipeline terminal operations.

Emissions, or carbon dioxide in the future, may be able to be sequestered and utilized in the surrounding oil fields for tertiary enhanced oil recovery of partially depleted formations. The refinery design will be without sequestering in the interest of minimizing the schedule and providing refined products to North Dakota, while utilizing their available stranded crude oils. The sequestering would be desirable, but is a project that will have to be tried on an operating refinery with adequate space left in the plot plan to accommodate collection and compression of the carbon dioxide. Study work will be required to determine what oil recovery methods will be used in this area 5 to 10 years from now.

Refinery Sizing Logic

The sizing of the refinery was reviewed and a 50,000 bbl/day refinery was considered but the incremental cost to start with a 100,000 bbl/day refinery was very attractive. It was a logical choice since adequate crude is available and the products can be easily marketed in the Dakotas. An initial refinery greater than 100,000 bbls/day capacity would require vessels that would be too large for transport to the site. Based on these limitations, it is strongly recommended that, in order to reduce financial risk and marketing risks, the refinery start at 100,000 bbls/day. This will keep the emissions low enough to easily obtain the construction permits and avoid using multiple towers to stay within transportation size limitations for vessels.

The plot plan will be designed to allow for expansion of the refinery. This will be more cost effective than building a larger refinery since the existence of a refinery at this location, purchasing local crude oils will impact the available crude mix. The change in crude mix may make it possible to increase the capacity by only modifying or adding selected units without duplicating the whole refinery. The market for refined products will also be impacted by the existence of a refinery in this location and will modify the mix of marketable refined products. A future expansion will allow the refinery to accommodate at a lower cost per barrel.

Refinery Units and Configuration:

Depending upon the configuration, the following units could be used within this refinery:

Atmospheric Crude Tower – This unit is the unit that first separates the crude oil into its proto products by boiling point. The streams that come from the atmospheric crude tower are an overhead gas stream, a C_3/C_4 stream that will become LPG, a naphtha stream that will be processed into gasoline blend components, a kerosene stream that will be processed into jet fuel, a light gas oil (LGO) that will become diesel fuel, and a bottoms stream that will be further processed into other transportation fuels and an asphaltic residue.

Vacuum Crude Tower – This unit takes the residue from the atmospheric tower, and distills it, under vacuum, into heavy vacuum gas oil (HVGO) and a residue. The HVGO will be cracked into transportation fuels, while the residue can either be partially cracked into transportation fuels or be sold as either a heavy fuel oil or asphalt.

Resid Hydrocracker – This unit will take the residue from the Vacuum Crude Tower and hydrocrack it into lighter products that are suitable for further processing. For the purposes of this study, a 75% conversion to the lighter products was assumed. This unit will produce the entire range of lighter products from gases to heavy gas oil.

Hydrocracker – This unit will take the heavy gas oils produced by the Vacuum Crude Unit and the Resid Hydrocracker and convert them into transportation fuels. Hydrocracking is preferred to Fluid Catalytic Cracking (FCC) in this case, because the hydrocracker can be operated to preferentially produce jet fuel and diesel fuel, while the FCC preferentially produces gasoline. The bottoms from this unit are typically a low sulfur fuel oil that has the properties of a semi-finished lube oil base stock. This provides an opportunity to upgrade the value of the bottoms product. This opportunity is not considered in this feasibility study.

Diesel Desulfurizer – This unit will remove the sulfur from the diesel streams. Modern units also have the capability to increase the cetane of the diesel fuel by opening the rings of the condensed ring components in the diesel fuel. This unit will generate some naphtha in addition to diesel fuel.

Naphtha Desulfurizer – This unit will remove the sulfur from the naphtha streams. This will protect the catalyst in the reformer, the next unit down stream. The reformer catalyst is based on noble metals, such as platinum and palladium, and is very expensive.

Reformer – This unit takes the desulfurized naphtha, and removes the C_6 hydrocarbons to eliminate the possibility of forming benzene in the reformer. This distillation column generates two streams, light naphtha, and reformer feed. The reformer feed reacts with a catalyst to make aromatic hydrocarbons and hydrogen in the reformer. This raises the octane of reformate a great deal. Light naphtha and reformate are recombined to make gasoline.

Caustic (NaOH) Treater – This unit removes some sulfur compounds from the kerosene stream to make jet fuel. This treatment will remove the acidic sulfur compounds, such as mercaptans, and leave more heavily bound sulfur compounds (such as thiophenes) in the jet fuel. This is important, since the jet fuel needs the sulfur compounds for lubricity.

Amine Unit – In the hydrotreating of sulfur laden streams, the sulfur is removed as hydrogen sulfide (H_2S) that comes out in the gas stream. All of these streams are combined and taken to the amine unit. The amine unit removes the acid gases (H_2S and CO_2) and concentrates them into a single stream. The sulfur free gases can either be taken into the refinery gas stream, or further processed to make LPG. In this study, it has been assumed that the LPG would have some economic value, and was separated out. The n-butane contained in the LPG has value as a gasoline blend stock for adjusting the RVP of the gasoline pool.

Sulfuric Acid – This unit will take the H_2S stream form the amine unit, and convert it into sulfuric acid. It does this by burning the H_2S over a catalyst to form SO_3 that is converted to sulfuric acid by adding water.

Cases Considered:

There are four cases considered. Each of these cases is based upon 100,000 bpd of crude oil feed. This feed rate was selected because it is currently about the minimum economic size for a refinery and because it would take about half of the projected available crude oil from the Williston Basin.

The four cases considered are:

1. **Red River C Crude** – This crude is currently being produced. It is a very light sweet crude. Because of this, it is easy to process, and takes the minimum amount of equipment to process. This should be the minimum capital case. This case would be the most expensive to modify later to accept other crudes, should Northwest Refining opt to do so. This case does not have either a resid hydrocracker or a vacuum tower. (Figure 1)

2. **North Dakota Sour Crude** – This crude is not currently being produced. Because it is both heavy and sour, it will take extensive hydroprocessing. This case will be the maximum capital case. This case configuration will handle all of the other cases, but could have idle equipment with some crude slates. This case has both a vacuum tower and a resid hydrocracker. (Figure 2)

3. **Blend Case** – This case is for a blend of 37,240 bpd of Heavy Sour Crude and 62,760 bpd Red River C Crude. This blend was selected because it will produce about 15,000 bpd of an asphaltic resid. This case does not have a resid hydrocracker, so approximately half of the resid comes from the vacuum tower, and half comes from the hydrocracker. The individual units are sized such that the refinery can be configured to become the North Dakota Sour Crude case by adding the resid hydrocracker and associated hydrogen plant. (Figure 3)

4. **Blend Case – HC** – This case has the same feed as the Blend Case. In this case, however, a resid hydrocracker was added that is adequate to process the vacuum resid generated by this crude slate. This case does not have the flexibility to handle more heavy crude than is assumed for the crude slate in this case. (Figure 2)

The Block Flow Diagrams for each of these cases are given in Figures 1 – 3. The Block Flow Diagrams for both the North Dakota Sour Crude Case and the Blend Case – HC Case are the same.

Material Balances:

The Material Balances for each of the cases are given in Table 1.

There are several assumptions within these Material Balances:

- The material balance for the Red River C crude is based upon a Simulated Distillation of the crude. This overall distillation should be accurate. The qualities and hydrocarbon type for each fraction within the crude are not known, and the sulfur distribution within the crude oil is not known.

- The distillation curve for the North Dakota Heavy Sour crude is a combination of two distillation curves – a Hemphill distillation of Madison crude to 620 °F, and a broad distillation for typical United States sour crude for the curve below 620°F. This typical crude may or may not have any resemblance to the high temperature end of the Madison crude distillation. The yields for diesel fuel, HVGO, and residue from the Madison crude could be significantly different from those actually used. This change in yields could be either good or bad for the overall project economics.

- The yields for each of the units were taken from the yields of similar units with feeds in the same boiling range. These feeds may not be the same as the feeds that will be available in North Dakota. The yield structure across the hydrotreating units will probably be different than those given. This is particularly true for the hydrocracking units. It is expected that the yields for the diesel and naphtha desulfurization units would be close to those that are used.

- The yields and quality of reformate will be highly dependent upon the hydrocarbon types in the naphtha feed. These yields will also affect the quantity of hydrogen produced in the reformer.

The best yield of jet plus diesel comes from running straight Red River crude. The case for straight North Dakota sour crude produces much less jet fuel, even with the resid hydrocracker. The loss in jet fuel corresponds to an increase in the production of asphalt. Economically, this is a very strong negative but is due to the nature of the crude oil.

Capital Expenditure:

The ISBL capital required for each of the cases is given in Table 2. These capital expenditure requirements for the Inside Battery Limits (ISBL) vary from $466,000,000 to $914,000,000. The difference is in the cost of the Resid Hydrocracker. The cases with the Resid Hydrocracker are much more expensive that those without the hydrocracker.

Another option is explored, which is called the Flexible Case. In this case, all of the individual units are sized to handle 100,000 bpd of either Red River or North Dakota Sour crude. The Resid Hydrocracker is not initially provided. This will enable the refinery to run either the light sweet or heavy sour crudes, as they become available. This will enable the refinery to avoid the big expenditure for the resid hydrocracker until they are assured of having enough heavy sour crude available to make this hydrocracker economically viable. The total ISBL cost for the refinery, using this approach is $956,000,000 or $42,000,000 more than would be required to build a refinery for only handling the North Dakota Heavy Sour crude. It can also be stated that the cost for this flexibility is $42,000,000 plus inflation.

Utility Requirements:

The utility requirements are given in Table 3. The natural gas requirements are given as net fuel requirements, with the refinery gas production being subtracted from the gross fuel gas required by the refinery, as shown in Table 6 below. There is a large amount of LPG produced that can be used to supply some of the net fuel consumption or be shipped by rail.

Table 6
Fuel consumption for the proposed refinery units with the Resid Hydrocracker

Unit	Fuel Gas Requirement, MM BTU/day
MPHC	2,506
Resid Hydrocracker	2,303
Diesel Desulfurization	471
Naphtha Desulfurization	591
Reforming	4,950
Crude Unit	856
Hydrogen Plant (including feed)	45,000
Total Requirements	**56,677**

Note:

The fuel can be either refinery gas or LPG or low sulfur fuel oil but the feed stock to the hydrogen plant is limited to fuel gas and LPG including C_4's.

The cases that include the Resid Hydrocracker require significantly more power and fuel gas than those cases that do not. This additional utility usage will provide more motor fuels, and provide the opportunity to consume LPG and low sulfur heavy fuel oil within the refinery operation with minimal power generation.

The sulfuric acid unit exports significant amounts of high pressure steam that could be used generate power and supply refinery process steam within the refinery to reduce purchased power.

Project Economics:

The ISBL capital costs were converted to project capital costs by adding 100% of ISBL capital for OSBL, excluding the pipeline cost, 3,000,000 barrels of tankage, and a 20% contingency. These data are given for the four basic cases in Table 4. In addition, the two stages for the Flexible case are given in Table 4, as Case 2 and 4.

These capital estimates are probably high, particularly for the cases that include a Resid Hydrocracker. As an example, the off sites for the Red River crude case with no Resid Hydrocracker are $436,000,000, while the off sites for the North Dakota crude case with a Resid Hydrocracker are $920,000,000. It is doubtful that the addition of a single unit would more than double the cost of the off sites.

The cost of Red River Crude was taken as the price of WTI at Cushing, OK. The cost of North Dakota Heavy Sour Crude was taken at $10/bbl below the price of WTI at Cushing. Product pricing was taken as the price in Los Angeles, CA, since they are both relatively remote, high-price locations.

Exceptions include LPG, which was priced at $7.00/MM BTU for its contained heat content. This assumes that there is no market for LPG, and that it needs to be burned in the refinery gas system. The asphaltic resid from either the vacuum tower or the Resid Hydrocracker was valued as fuel oil, and the resid from the Hydrocracker was valued as Gas Oil, since it would be a very good FCC feed.

The operating cost for the refinery was assumed to be $1.70/bbl. This is based upon an average cost for refinery operations given in a Solomon report on refining.

These data are analyzed for overall project economics in Table 5. It should be noted that no allowance for either depreciation or federal income tax was made. These economics show that the Red River Crude Case has the best payout of 1.4 years. The North Dakota Heavy Sour Case pays out in 2.1 years. Both of these are excellent payouts. Not unsurprisingly, the two blend cases are in between these two extremes. The blend case with no Resid Hydrocracker pays out in 1.6 years, and the blend case with a Resid Hydrocracker pays out in 2.2 years. It should be noted that the Hydrocracker for this blend case is sized only for the blend case, and no room for either expansion or heavier crudes is provided.

The Flexible Case shows a very good payout of 1.4 years without the Resid Hydrocracker. The incremental capital for adding the Resid Hydrocracker is not as good, with it having a payout of 3.7 years. (It should be noted that the off sites for this case are probably high, as discussed above, and that the payout is probably better than this.) The overall payout for the total project in the Flexible Case is 2.1 years, which is very good.

Other things that can affect the economics for the proposed refinery are:

Crude oil price: The Red River crude could well be worth more than World Trade Index (WTI), since it is light sweet crude. The North Dakota Heavy Sour crude could have much more than a $10/bbl discount from WTI, because it is very heavy and very sour. If either of these scenarios is true, then the relative economics for the various cases will come closer together.

Product Prices: The assumed product prices are probably wrong. They were taken at Los Angeles, because both LA and North Dakota are fairly remote from the refining hub in the Gulf Coast. It was also possible to obtain both product and crude pricing on the same day using these assumptions.

Capital Estimate: The OSBL capital estimate for the Resid Hydrocracker cases is probably high for the reasons discussed above. Reducing the capital for these cases will improve their economics.

Operating Costs: The Solomon estimated cost for an average refinery was assumed. This may or may not be the case for the refinery. The overall economics are not very sensitive to operating costs. For instance, raising the operating costs by $1.00 per barrel only increases the payout by 0.1 years.

These economics are conservative; the changes in the basic assumptions are expected to improve the economics. The North Dakota Heavy Sour Crude would probably be more heavily discounted. Product prices at the pump seem to be higher in North Dakota than in Los Angeles. The Resid Cracking cases capital is probably high.

Project Timeline:

The time from issuance of the construction permit(s) and financing, because long delivery items that are currently running over 36 months from order to delivery, plus the normal procurement cycle requiring some preliminary engineering and solicitation of bids, the delivery of some major items could be as much as 42 months from start of detailed engineering and another 3 to 6 months to complete construction. This schedule could take up to 5 years from the time the permits are issued and financing is in place to complete the refinery.

Some options are available for some limited operation prior to completion of the full refinery possibly on a campaign basis to make limited products using simple topping methods and minimal treatment of the products. The options and economics of these options will be evaluated as the project progresses.

Conclusion:

The economics are good, and the project should be pursued to the next phase: permitting and more detailed crude analysis resulting in a more detailed FEED study in preparation for detailed engineering. The FEED study would provide a more accurate cost estimate and evaluation of the utilities and offsites required plus a more in-depth marketing and supply study. The results of this study will supply the detailed information required to obtain financing for the project and allow it to go into detailed design.

There are many aspects of this study that require more research and the principals of Northwest Refining, Inc. along with ENGlobal Engineering will continue to pursue the project until questions and concerns are answered. Based on the dynamics of the crude supply, and the unknown impact the refinery will have on the crude supply, the refinery will be designed with some flexibility to accommodate expected changes in the charter of the available crude. Northwest Refining, Inc. officials are formatting the next phase of the process and will start the next phase as soon as the preliminary study is complete with a favorable conclusion that will permit the process to continue into the permitting and design phase.

ATTACHMENTS

TABLES & FIGURES

Table 1
Northwest Refining
Williston Refinery
Case Material Balances

Case Description			Case 1 Red River Crude	Case 2 North Dakota Sour Crude	Case 3 Blended Crudes	Case 4 Blended Crudes; Resid Hydrocracker
Crude Oil Charge	units					
Red River	bpd		100000		37240	37240
North Dakota Sour	bpd			100000	62760	62760
Products						
Refinery Gas	MM BTU/hr		119	898	444	524
LPG	bpd		5584	7220	4939	5997
Gasoline	bpd		22279	22521	19670	22534
Jet Fuel	bpd		42290	29818	35814	37141
Diesel Fuel	bpd		33112	34574	25998	33682
Heavy Low Sulfur Fuel	bpd		3562	7543	6406	7641
Asphalt	bpd		0	8153	15696	3963
Sulfuric Acid	ST/day		234	830	202	457
Jet + Diesel	bpd		75402	64392	61812	70823

Table 2
Northwest Refining
Williston Refinery
Case ISBL Capital Requirements

		Case 1 Red River Crude		Case 2 North Dakota Sour Crude		Case 3 Blended Crudes		Case 4 Blended Crudes; Resid Hydrocracker		Flexible Case
		Size, M BPD	Cost, $MM	Size, M BPD	Cost, $MM	Size, M BPD	Cost, $MM	Size, M BPD	Cost, $MM	Cost, $MM
ISBL Unit										
Crude Unit	M BPD	100	60	100	90	100	90	100	90	90
Resid Cracker	M BPD	0	0	33	396	0	0	16	256	0
Hydrocracker	M BPD	36	150	36	150	31	137	37	153	153
Diesel Desulfurizer	M BPD	10	26	14	32	9	25	13	30	32
Naphtha Desulfurizer	M BPD	19	25	20	26	18	24	20	26	26
Reformer	M BPD	18	76	18	76	15	69	18	76	76
Hydrogen	MM scfd	66	75	107	100	58	69	89	90	69
Amine	MM scfd	1715	4	6100	8	1477	4	3347	4	8
Sulfuric Acid Plant	ST/day	234	20	830	42	202	20	457	26	43
Caustic Treater	M BPD	43		30		36		37		
			436		920		438		751	497
Comments		No Vacuum Tower, or Resid Hydrocracker				No Resid Hydrocracker				Resid Hydrocracker to be added later
Additional Cost of Resid Hydrocracker and Hydrogen Plant										459

Table 3
Northwest Refining
Williston Refinery
ISBL Utility Requirements

Refinery Total Consumption	Units		Case 1		Case 2		Case 3		Case 4	
			Amount Produced	Net Required	Amount Produced	Net Required	Amount Produced	Net Required	Amount Produced	Net Required
Power	KW			29009		62043		27063		46386
Fuel Gas	MM BTU/hr		119	1694	898	1823	444	1284	524	1840
Low BTU Gas	MMBTU/hr			0		0		0		0
Cooling Water	gpm			20692		31536		23094		28241
Boiler Feed Water	gpm			1053		1262		949		1183
LP Steam	M#/hr			102		133523		103		64803
MP Steam	M#/hr			63		175		60		119
HP Steam	M#/hr			-144		-324		-125		-222

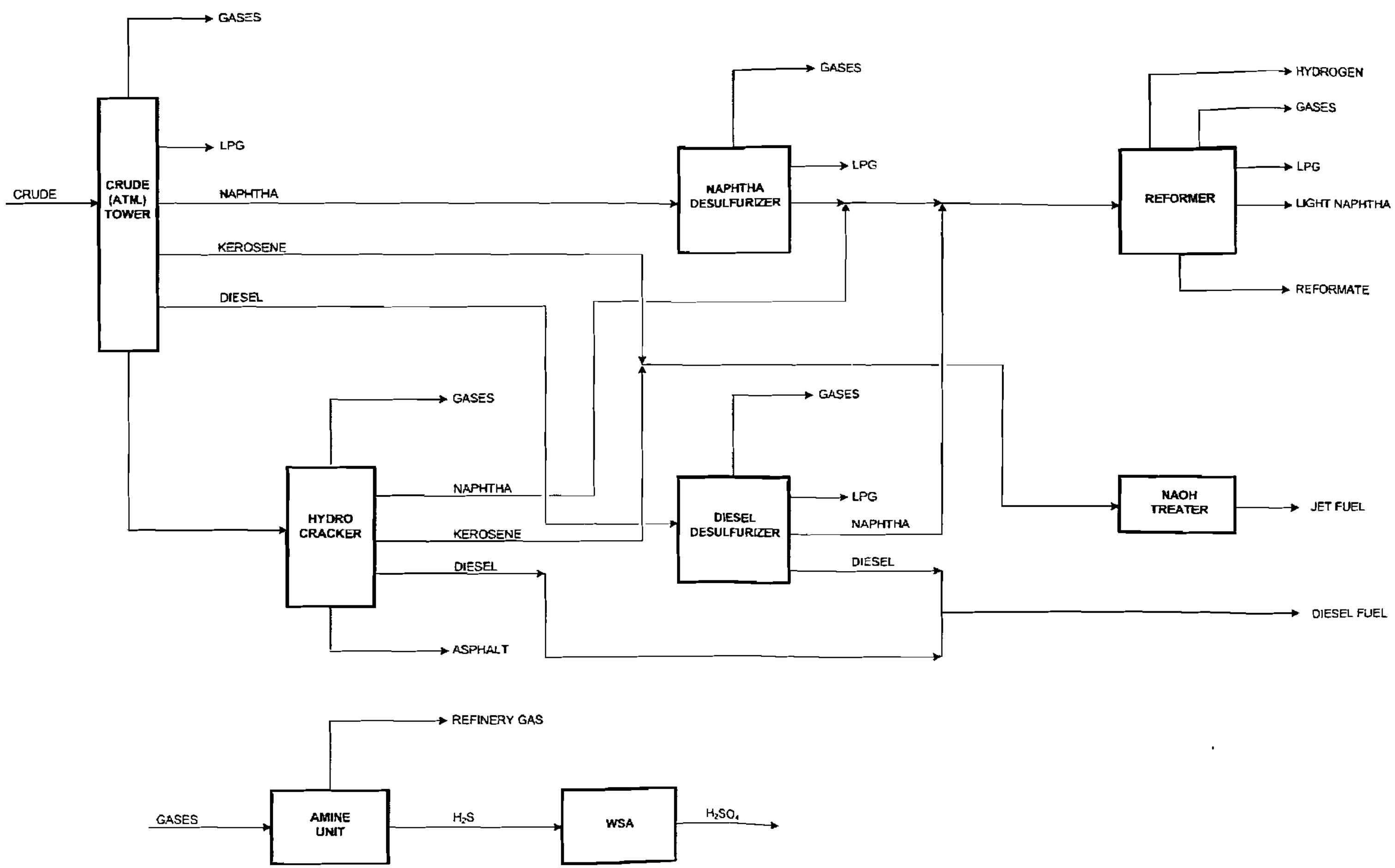
Table 4
Northwest Refining
Williston Refinery
Total Project Costs
in Millions of Dollars

			Case 1	Case 2	Case 3	Case 4
ISBL			436	920	438	751
OSBL	@ 100% of ISBL		436	920	438	751
Tankage	@ $18/bbl		54	54	54	54
Pipeline			233	233	233	233
Total Project Capital			1159	2127	1163	1789

Table 5
Northwest Refining
Williston Refinery
Economic Analyses

Case		Red River		North Dakota Sour		North Dakota Blend		North Dakota Blend HC		Resid Cracker Economics
	Price	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	
)aily :osts and Revenues										
:rude										
Red River	108.7	100000	10870000			62,760	6822012	62,760	6822012	
North Dakota	98.7			100000	9870000	37,240	3675588	37,240	3675588	
		100000	10870000	100000	9870000	100000	10497600	100000	10497600	
'roducts										
Refinery Gas	7	119	19992	898	150864	444	74592	524	3668	
LPG	30.8	5584	171987	7220	222376	4939	152121	5997	184707.6	
Gasoline	116.97	22279	2605975	22521	2634281	19670	2300800	22534	2635801.98	
Jet Fuel	135.74	42290	5740445	29818	4047495	35814	4861392	37141	5041519.34	
Diesel Fuel	132.6	33112	4390651	34574	4584512	25998	3447335	33682	4466233.2	
Fuel Oil	120.9012	3562	430650	7543	911958	6406	774493	7641	923806.0692	
Asphalt	88.4898	0	0	8153	721457	15696	1388936	3963	350685.0774	
Sulfuric Acid	60	234	14040	830	49800	202	12120	457	27420	
'otal Sales			13353748		13171880		12937197		13630173	
Gross Margin, $			2483748		3301880		2439597		3132573	
Operating Cost, $	1.7	100000	170000	100000	170000	100000	170000	100000	170000	
Gross Profit, $			2313748		3131880		2269597		2962573	
Annual Gross Margin, $MM			809.8		1096.2		794.4		1036.9	301.8
Capital Expend, $MM			1159		2127		1163		1789	964
Payout, years			1.4		1.9		1.5		1.7	3.2

FIGURE 1



ENGlobal® Engineering, Inc. Global Thinking...Global Solutions	FIGURE 1. NORTH DAKOTA RED RIVER C CRUDE BLOCK FLOW DIAGRAM CASE 1		
Scale NA	Project No. 10-171649	Drawing No. 001	Rev B

FIGURE 2

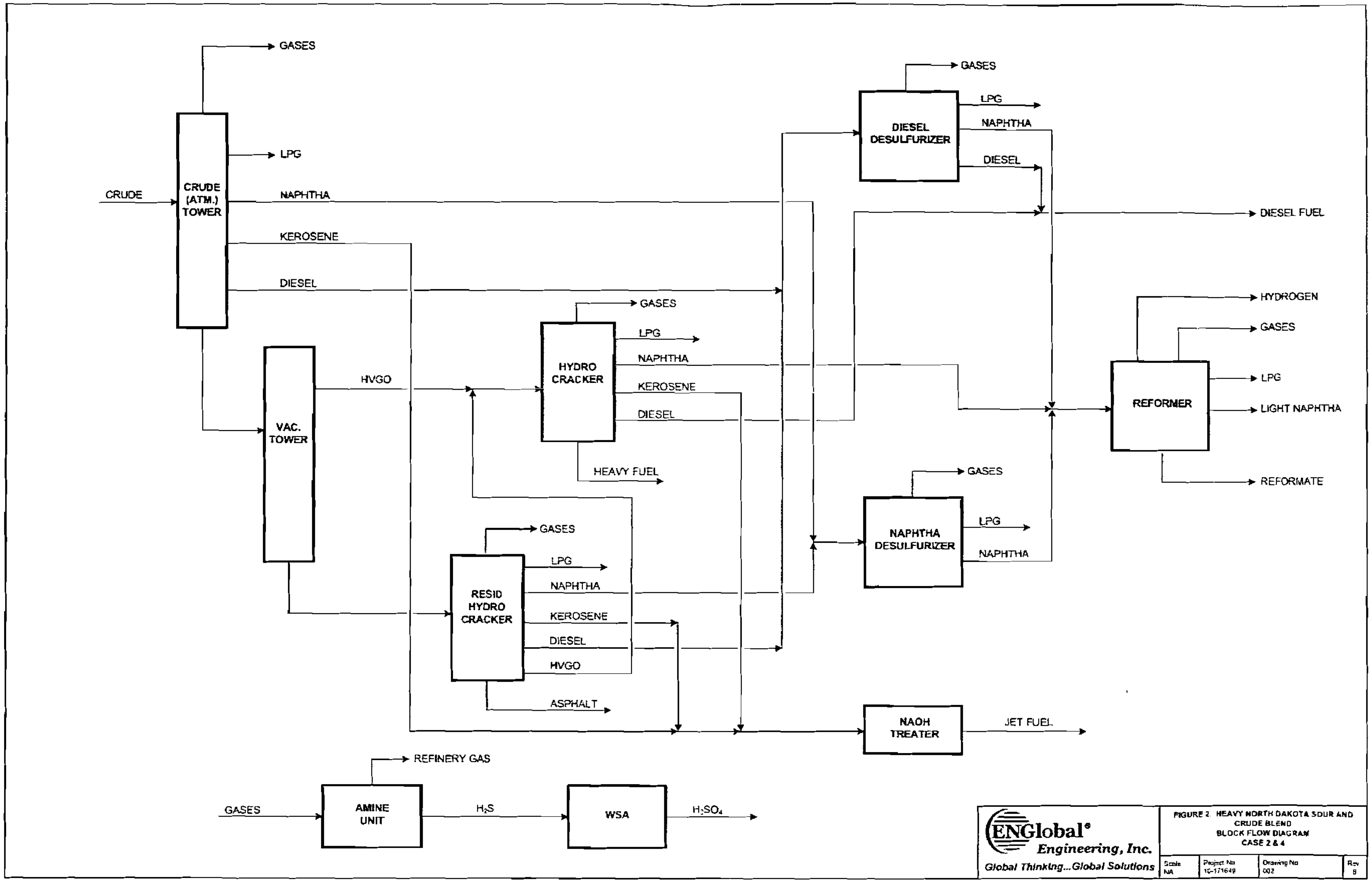
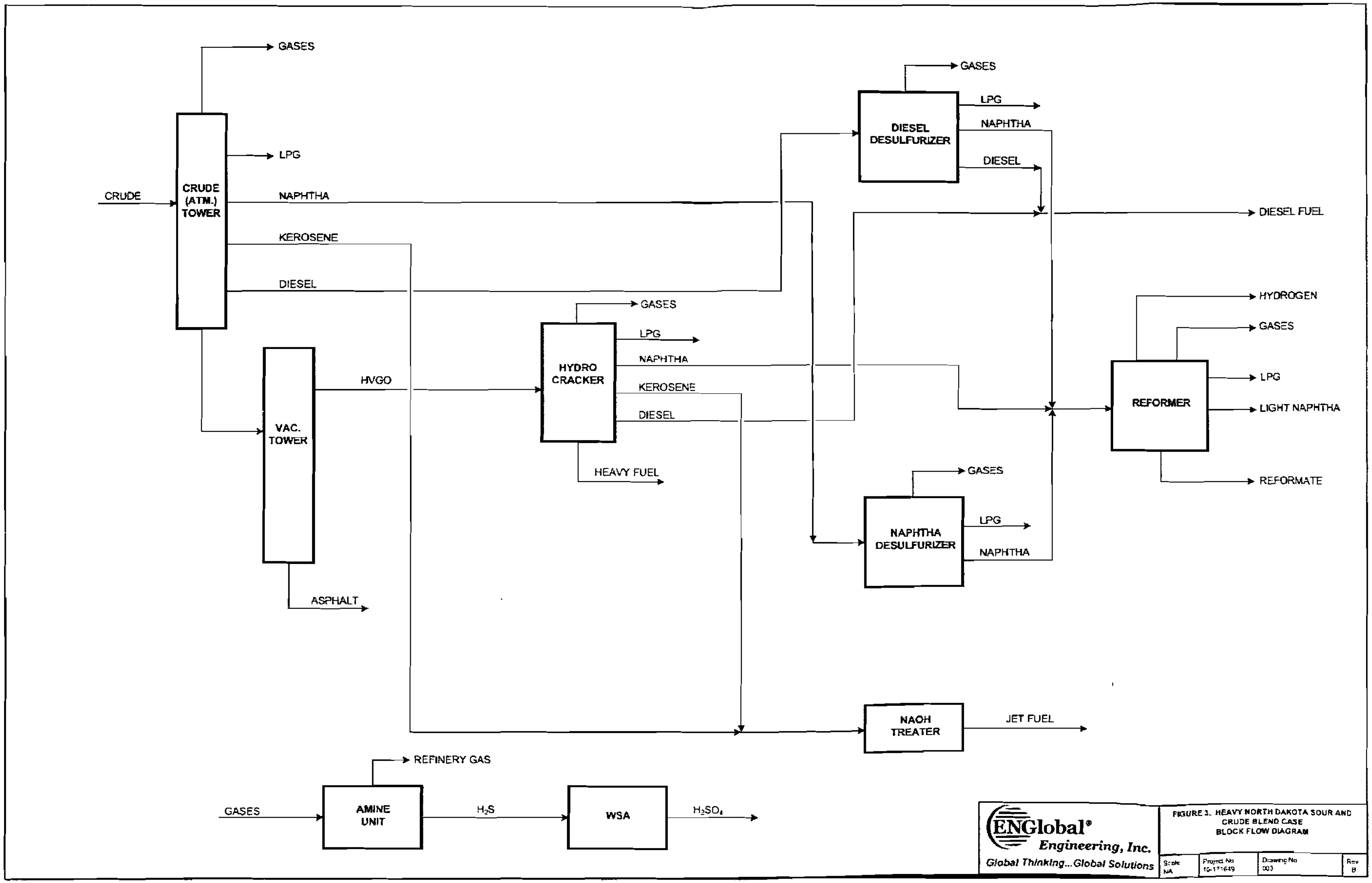

GASES
CRUDE
CRUDE (ATM.) TOWER
LPG
NAPHTHA
KEROSENE
DIESEL
VAC. TOWER
HVGO
GASES
HYDRO CRACKER
LPG
NAPHTHA
KEROSENE
DIESEL
HEAVY FUEL
GASES
RESID HYDRO CRACKER
LPG
NAPHTHA
KEROSENE
DIESEL
HVGO
ASPHALT
GASES
DIESEL DESULFURIZER
LPG
NAPHTHA
DIESEL
DIESEL FUEL
GASES
NAPHTHA DESULFURIZER
LPG
NAPHTHA
HYDROGEN
GASES
REFORMER
LPG
LIGHT NAPHTHA
REFORMATE
NAOH TREATER
JET FUEL
REFINERY GAS
GASES
AMINE UNIT
H_2S
WSA
H_2SO_4
ENGlobal® Engineering, Inc.
Global Thinking...Global Solutions
FIGURE 2 HEAVY NORTH DAKOTA SOUR AND CRUDE BLEND
BLOCK FLOW DIAGRAM
CASE 2 & 4
Scale NA
Project No 10-171649
Drawing No 002
Rev B

FIGURE 3


GASES
CRUDE
CRUDE (ATM.) TOWER
LPG
NAPHTHA
KEROSENE
DIESEL
VAC. TOWER
HVGO
ASPHALT
HYDRO CRACKER
GASES
LPG
NAPHTHA
KEROSENE
DIESEL
HEAVY FUEL
DIESEL DESULFURIZER
GASES
LPG
NAPHTHA
DIESEL
DIESEL FUEL
REFORMER
HYDROGEN
GASES
LPG
LIGHT NAPHTHA
REFORMATE
NAPHTHA DESULFURIZER
GASES
LPG
NAPHTHA
NAOH TREATER
JET FUEL
AMINE UNIT
REFINERY GAS
GASES
H_2S
WSA
H_2SO_4
ENGlobal® Engineering, Inc.
Global Thinking...Global Solutions
FIGURE 3. HEAVY NORTH DAKOTA SOUR AND CRUDE BLEND CASE BLOCK FLOW DIAGRAM
Scale NA
Project No 10-171649
Drawing No 003
Rev B

ENGlobal® Engineering, Inc.	Northwest Refining	Project No. 10-171649
	Feasibility Study Rev B 4-10-2008	

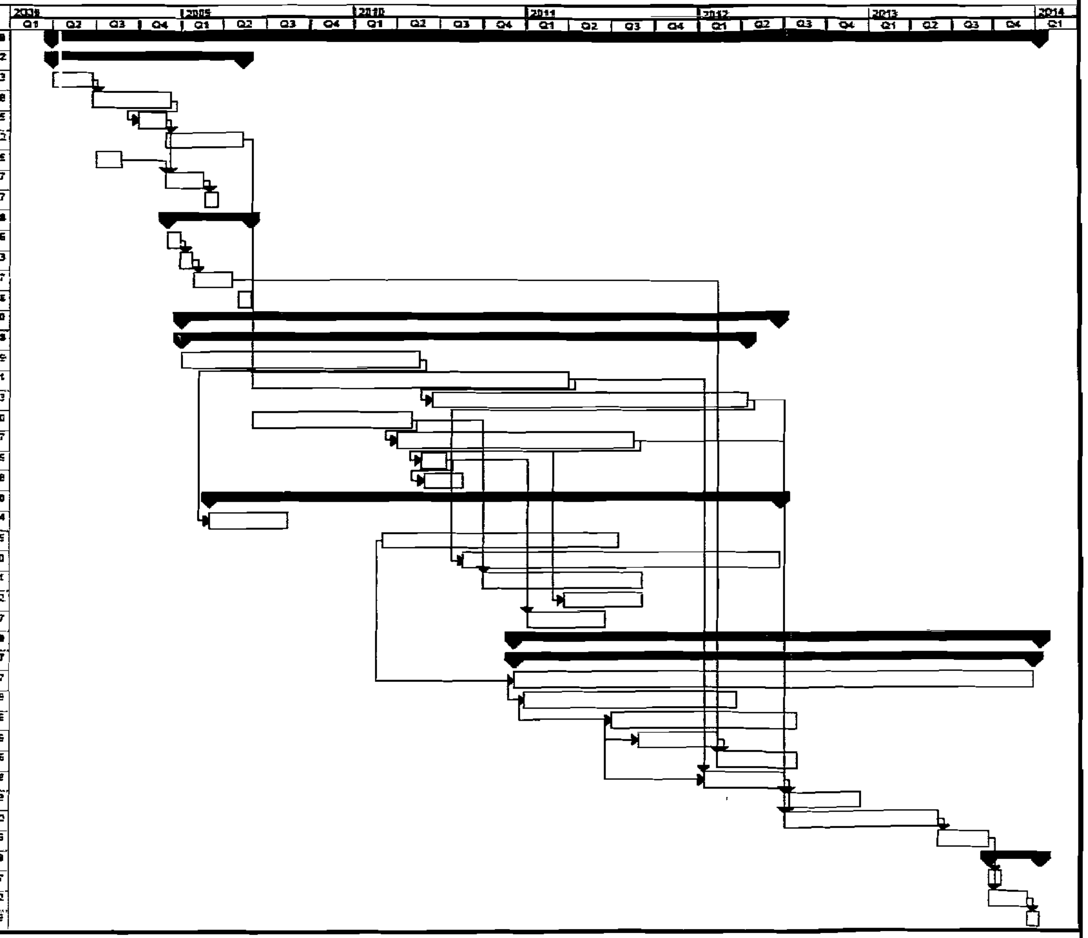
PROJECT SCHEDULE

ENGlobal Engineering, Inc.

NORTH WEST REFINING

Apr 14

ID	WBS	Task Name	Duration	Start	Finish
1		**North West Refining**	**1698 days**	**Apr 1**	**Jan 8**
2	1.0	**Feasibility Report**	**291 days**	**Apr 1**	**May 12**
3	1.1	Environmental Permit Preparation	3 mons	Apr 1	Jun 23
4	1.2	Permit Review and Issuance	6 mons	Jun 24	Dec 8
5	1.3	Detail analysis of available crude	2 mons	Oct 1	Nov 25
6	1.4	FEED study to determine units to be used	6 mons	Nov 26	May 12
7	1.5	Contact licenser and execute NDAs	2 mons	Jul 1	Aug 25
8	1.6	Select optimum licensor based on bids	3 mons	Nov 26	Feb 17
9	1.7	Prepare Bankable study with pipeline	1 mon	Feb 18	Mar 17
10	2.0	**Start Detail Engineering**	**120 days**	**Dec 1**	**May 28**
11	2.1	Land acquisition	1 mon	Dec 1	Dec 26
12	2.2	Soil data	1 mon	Dec 29	Jan 23
13	2.3	Identify and order long lead items	3 mons	Jan 26	Apr 17
14	2.4	Develop plot plan	1 mon	May 1	May 28
15	3.0	**Detail Engineering and Procurement**	**906 days**	**Jan 1**	**Jun 20**
16	3.1	**Engineering**	**867 days**	**Jan 1**	**Apr 13**
17	3.1.1	Civil Specs & Detail Engineering	18 mons	Jan 1	May 19
18	3.1.2	Mech/Piping Specs & Detail Engineering	24 mons	Jun 1	Apr 1
19	3.1.3	Elect/IE Specs & Detail Engineering	24 mons	Jun 14	Apr 13
20	3.1.4	Process Specs & Detail Engineering	12 mons	Jun 1	Apr 30
21	3.1.5	Automation Specs & Detail Engineering	18 mons	Apr 1	Aug 17
22	3.1.6	Estimate for Bulk Commodities	2 mons	May 21	Jul 15
23	3.1.7	Fabrication Needs Identified	3 mons	May 27	Aug 18
24	3.2	**PROCUREMENT**	**863 days**	**Mar 2**	**Jun 20**
25	3.2.1	Civil	6 mons	Mar 2	Aug 14
26	3.2.2	Mech/Piping	18 mons	Mar 1	Jul 15
27	3.2.3	Elect/IE	24 mons	Aug 15	Jun 20
28	3.2.4	Process	12 mons	Oct 1	Sep 1
29	3.2.5	Automation	6 mons	Mar 21	Sep 2
30	3.2.6	Bulk Commodities	6 mons	Jan 3	Jun 17
31	4.0	**CONSTRUCTION/STARTUP**	**808 days**	**Dec 8**	**Jan 8**
32	4.1	**CONSTRUCTION**	**808 days**	**Dec 8**	**Dec 27**
33	4.1.1	QA/QC Auditing & Testing	40 mons	Dec 6	Dec 27
34	4.1.2	Site Prep	16 mons	Dec 28	Mar 19
35	4.1.3	Civil Construction & Installation	14 mons	Jul 1	Jul 26
36	4.1.4	Large Equipment Set Up	6 mons	Aug 26	Feb 5
37	4.1.5	Long Lead Items Installation	6 mons	Feb 10	Jul 26
38	4.1.6	Mech/Piping Construction & Installation	6 mons	Jan 13	Jun 28
39	4.1.7	Elect/IE Construction & Installation	6 mons	Jun 29	Dec 12
40	4.1.8	Automation Construction & Installation	12 mons	Jun 29	May 30
41	4.1.9	Commissioning of Equipment	4 mons	May 31	Sep 19
42	4.2	**COMMISSIONING/STARTUP**	**80 days**	**Sep 20**	**Jan 8**
43	4.2.1	Warranty	1 mon	Sep 20	Oct 17
44	4.2.2	Testing/Commissioning	3 mons	Sep 20	Dec 12
45	4.2.3	Start Operation of all units	1 mon	Dec 13	Jan 9



Date: Apr 14

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone

ENGlobal
ENGLOBAL ENGINEERING, INC.

Review & Comment Transmittal

This is an ISO 9000 From and must not be modified without proper approval
Q.9.1.2-1. Rev. 5 (10-17-01)

Project No.: 10171649
Project Title: WILLISTON OIL REFINERY

Transmittal Date: 02/26/08
Transmittal Number: DT-171649-001

To: NORTHWEST REFINING, INC.
13988 W. FRONT STREET
WILLISTON, ND 58801

Attention: MEL FALCON

Description: NW REFINING PIPELINE ESTAMATE
Remark: PLEASE RETURN A SIGNED COPY OF THIS TRANSIMTTAL TO ENGLOBAL ENGINEERING FOR VERIFICATION OF RECEIPT TO:
EMAIL: DENA.ESSNER@ENGLOBAL.COM
FAX: 281-878-1010
Document Count: 2

Document Number	Rev	Document Title	File Name
PIPELINE & TERMINAL COST	0	PIPELINE & TERMINAL COST	
TERMINAL COST	2	TERMINAL COST	

* - Drawings attached For Reference Only

Distribution: X = Xerox Copy O = Original B = Blueline R = Reduced Set E = Electronic File

FALCON, MEL REEVES, GARY G

Dena Essner for Larry Presswood

LARRY W. PRESSWOOD Phone: (281) 878-1000
ENGLOBAL ENGINEERING, INC. FAX: (281) 878-1010
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HOUSTON, TX 77060

ENGlobal®
Engineering, Inc.

April 15, 2008
Rev 0

NORTHWEST REFINING, INC.
PIPELINE & TERMINAL COST

An analysis was conducted to estimate the construction of a new refined products pipeline for the proposed refinery in Marley, ND. Two cases were evaluated for the refinery, case 1 is for 50,000 bbl/day refinery and case 2 is for 100,000 bbl/day refinery. For case 1, two segments of pipeline are recommended. The first segment is an 8" pipeline from the refinery in Marley, ND to an expanded Cenex terminal in Minot, ND. The second segment is a 12" pipeline from the refinery in Marley, ND to a new terminal in Belfield, ND. For case 2, three segments of pipeline are recommended. The first two are the same as in case 1 with the addition of a third segment from Belfield, ND to a new terminal in Spearfish, SD. The following summarizes the details and costs of each segment.

8" pipeline from refinery to Minot, ND

The distance from the proposed refinery site to Minot, ND is approximately 142 miles. The cost for this section of pipeline is $39,340,300 which includes labor, materials, inspection, right of ways, and pumping stations. An additional amount of $13,500,000 is required to expand the terminal in Minot, ND to allow for proper storage of 250,000 barrels of refined products. The total terminal and pipeline cost for this segment is $52,840,300.

12" pipeline from refinery to Belfield, ND

The distance from the proposed refinery site to Belfield, ND is approximately 131 miles. The cost for this section of pipeline is $49,855,458 which includes labor, materials, inspection, right of ways, and pumping stations. An additional amount of $13,500,000 is required to install a new terminal in Belfield, ND to allow for proper storage of 250,000 barrels of refined products. The total terminal and pipeline cost for this segment is $63,355,458.

12" pipeline from Belfield, ND to Spearfish, SD

The distance from Belfield, ND to Spearfish, SD is approximately 187 miles. The cost for this section of pipeline is $70,034,329 which includes labor, materials, inspection, right of ways, and pumping stations. An additional amount of $27,000,000 is required to install a new terminal in Spearfish, SD to allow for proper storage of 500,000 barrels of refined products. The total terminal and pipeline cost for this segment is $97,034,329.

In summary, the total pipeline and terminal cost for Case 1 – 50,000 bbl/day refinery is $135,635,758. The total pipeline and terminal cost for Case 2 – 100,000 bbl/day refinery is $232,670,087. Both of these cases also include a cost of $19,440,000 for 360,000 barrels of storage at the refinery itself. The cost to acquire land for the terminals and pumping stations has not been included in this estimate. These cost estimates have an accuracy of ± 30% and are based on current market prices and are projected to escalate in the future.

NW Refining - Pipeline & Terminal Cost

<u>ASSUMPTIONS:</u>

Tankage cost/barrel	$ 18.00
Right of way cost/ft	$ 3.00
Carbon steel material, cost per LB	$ 0.54
8" pipe material, lbs per foot	28.55
12" pipe material, lbs per foot	49.56
Truck weight capacity, LBS	45,000
Freight charge per truck	$ 1,000

Refinery	**Case 1**		**Case 2**	
Refinery production rate	50,000	bbls/day	100,000	bbls/day
Refinery product storage - days	10		5	
Gasoline production	12,000	bbls/day	24,000	bbls/day
Diesel production	12,000	bbls/day	24,000	bbls/day
Jet Fuel production	12,000	bbls/day	24,000	bbls/day
Refinery Gasoline storage	120,000	bbls	120,000	bbls
Refinery Diesel storage	120,000	bbls	120,000	bbls
Refinery Jet Fuel storage	120,000	bbls	120,000	bbls
Refinery Gasoline tank cost	$ 2,160,000		$ 2,160,000	
Refinery Diesel tank cost	$ 2,160,000		$ 2,160,000	
Refinery Jet Fuel tank cost	$ 2,160,000		$ 2,160,000	
Refinery Tank construction cost	$ 12,960,000		$ 12,960,000	
Total Refinery Tankage cost	**$ 19,440,000**		**$ 19,440,000**	
Minot Terminal				
Total Capacity	250,000	bbls	250,000	bbls
Gasoline storage	75,000	bbls	75,000	bbls
Diesel storage	75,000	bbls	75,000	bbls
Jet Fuel storage	100,000	bbls	100,000	bbls
Tankage Cost	$ 4,500,000		$ 4,500,000	
Tank construction cost	$ 9,000,000		$ 9,000,000	
Total Tankage cost	**$ 13,500,000**		**$ 13,500,000**	
Distance from Refinery	142	miles	142	miles
Right of way cost	$ 2,249,280		$ 2,249,280	
8" Pipe cost	$ 11,559,050		$ 11,559,050	
8" Pipe Installation	$ 16,494,720		$ 16,494,720	
8" Block valve settings	$ 100,000		$ 100,000	
Bore/Drill 18" dirt	$ 974,688		$ 974,688	
Pig launchers / receivers	$ 240,000		$ 240,000	
Pipe freight	$ 476,000		$ 476,000	
Inspection cost	$ 2,246,562		$ 2,246,562	
Pumping station cost	$ 5,000,000		$ 5,000,000	
Total Pipeline Cost	**$ 39,340,300**		**$ 39,340,300**	

I-90 (Belfield) Terminal

Total Capacity	250,000	bbls	250,000	bbls
Gasoline storage	125,000	bbls	125,000	bbls
Diesel storage	125,000	bbls	125,000	bbls
Tankage Cost	$ 4,500,000		$ 4,500,000	
Tank construction cost	$ 9,000,000		$ 9,000,000	
Total Tankage cost	**$ 13,500,000**		**$ 13,500,000**	
Distance from Refinery	131	miles	131	miles
Right of way cost	$ 2,075,040		$ 2,075,040	
12" Pipe cost	$ 18,511,017		$ 18,511,017	
12" Pipe Installation	$ 19,367,040		$ 19,367,040	
12" Block valve settings	$ 105,000		$ 105,000	
Bore/Drill 12" dirt	$ 881,892		$ 881,892	
Pig launchers / receivers	$ 219,000		$ 219,000	
Pipe freight	$ 762,000		$ 762,000	
Inspection cost	$ 2,934,469		$ 2,934,469	
Pumping station cost	$ 5,000,000		$ 5,000,000	
Total Pipeline Cost	**$ 49,855,458**		**$ 49,855,458**	

I-94 (Spearfish) Terminal

Total Capacity	N/A	bbls	500,000	bbls
Gasoline storage	N/A	bbls	100,000	bbls
Diesel storage	N/A	bbls	100,000	bbls
Jet Fuel storage	N/A	bbls	300,000	bbls
Tankage Cost	N/A		$ 9,000,000	
Tank construction cost	N/A		$ 18,000,000	
Total Refinery Tankage cost	N/A		**$ 27,000,000**	
Distance from I-90 (Belfield)	N/A	miles	187	miles
Right of way cost	N/A		$ 2,962,080	
12" Pipe cost	N/A		$ 26,424,123	
12" Pipe Installation	N/A		$ 27,646,080	
12" Block valve settings	N/A		$ 175,000	
Bore/Drill 12" dirt	N/A		$ 1,258,884	
Pig launchers / receivers	N/A		$ 292,000	
Pipe freight	N/A		$ 1,087,000	
Inspection cost	N/A		$ 4,189,162	
Pumping station cost	N/A		$ 6,000,000	
Total Pipeline Cost	N/A		**$ 70,034,329**	
TOTAL PIPELINE & TERMINAL COST	**$ 135,635,758**		**$ 232,670,087**	